ECONOMIC ANALYSIS OF DEVONIAN GAS SHALE DRILLING VENTURES INVOLVING FRACTURE STIMULATION

OCTOBER 1977

Prepared by

TRW
ENERGY SYSTEMS PLANNING DIVISION
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DEPARTMENT OF ENERGY

Under Contract EY-77-C-21-8085

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ACKNOWLEDGMENTS

This Economic Analysis of Devonian Gas Shale Drilling Ventures Involving Fracture Stimulation has been developed as an element of Contract No. EY-77-C-21-8085 under the direction of Mr. Charles A. Komar at DOE's Morgantown Energy Research Center (MERC), located at Morgantown, West Virginia. The following TRW personnel were responsible for developing the report.

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ABSTRACT

The objective of this study is to determine the economics of gas production in the Devonian Shales of the Appalachian Basin using normal and massive hydraulic fracturing techniques under various assumed production/operation conditions. The study was authorized by, and performed under direction of the Morgantown Energy Research Center. Generalized production decline curves were provided by the Morgantown Energy Research Center for use with the TRW ECONGAS economic program which was used to compute the required natural gas selling price to obtain a specified value of Return on Investment (ROI).

Three different types of operation were identified: (1) utility, (2) independent driller, and (3) self-help industry. Each operation-type was evaluated using two sets of generalized production decline curves, Scenarios A and B. Scenario A consists of three curves which are based on initial open flow rates of (1) 350 MCFD, (2) 200-300 MCFD and (3) 50-175 MCFD, respectively. Scenario B consists of two curves which are based on initial open flow rates of (1) 350 MCFD and (2) 250 MCFD, respectively. Each scenario was evaluated with respect to discounted cash flow rate of return on well investment, investment payout period and profit investment ratio (PIR). For evaluation of wellhead price determinations, various base wellhead gas prices were established for the interstate and intrastate markets for the different operation examples.

The results of the study show that an acceptable return on investment is possible for Massive Hydraulic Fracturing cases for all types of operation (utility, independent, self-help) at prevailing prices if average well production corresponding to an initial open flow of 350 MCFD is attainable. These results correspond to investment payout times ranging between 3 and 6 years, depending on the type of operation, and PIR values greater than unity. The comparative data for the less expensive normal hydraulic fracturing examples are of course much better. Detailed results of the study are presented in Section 3 along with a discussion of results in Section 4.

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ACRONYMS

DCF	Discounted Cash Flow
DOE	Department of Energy
FPC	Federal Power Commission (now part of the DOE)
HF	Hydraulic Fracturing
IRS	Internal Revenue Service
MERC	Morgantown Energy Research Center
MHF	Massive Hydraulic Fracturing
NPV	Net Present Value
PIR	Profit Investment Ratio
ROI	Return on Investment

1.0 INTRODUCTION

1.1 BASIS FOR THE STUDY

Recent increased demand for gas, coupled with better wellhead has prices and good prospects for even higher gas prices, have led operators to devote more attention to the development of the low-permeability Devonian gas shales in the Appalachian Basin.

The study, authorized by the Morgantown Energy Research Center (MERC), was performed by TRW under Contract EY-77-C-21-8085, to determine natural gas prices for a variety of investment options which would be necessary for economical gas production using massive hydraulic fracturing (MHF) technology. Values used for the cost of MHF were $70,000 and $100,000. Corresponding natural gas prices were also determined for normal hydraulic fracturing at a fracture treatment cost of $12,000.

THE SAME GENERALIZED PRODUCTION DECLINE DATA (SECTION 1.3) WERE USED IN THIS STUDY TO REPRESENT GAS PRODUCTION LEVELS FOR BOTH NORMAL AND MHF CASES. THE GENERALIZED DATA ARE BASED ON ACTUAL PRODUCTION FROM WELLS WHICH WERE FRACTURED BY NORMAL HYDRAULIC FRACTURE TREATMENTS (1000 BBLS) AND <u>DO NOT</u> REPRESENT EXPECTED RESULTS FROM MHF TREATMENTS. THE ONLY PURPOSE OF THE DATA IS TO PROVIDE A BASIS FOR ECONOMIC EVALUATION OF MHF ALTERNATIVES. COMPARABLE EVALUATION DATA FOR NORMAL HYDRAULIC FRACTURE EXAMPLES ARE PROVIDED FOR REFERENCE, NOT FOR COMPARATIVE EVALUATION OF NORMAL AND MHF METHODS.

1.2 DEVONIAN SHALE AS A RESOURCE

It has been established geologically that a potentially significant source of methane is the Mississippian-Devonian shales of the Appalachian Basin which extends from northern New York to Alabama. Resource estimates range from 3 to 400 trillion cubic feet of gas (MOPPS, 1977). These same shales extend westward through the Michigan and Illinois basins into the mid-continent area and have a total potential producing area of approximately 250,000 square miles. The shales are distributed in discrete units ranging in thickness from a few feet to about 400 feet, contain organic matter ranging from 5 to 25 percent of the shale, and yield as much as 7 million BTU per ton of shale by direct combustion. In the past, comparatively little attention has been devoted to these Mississippian-Devonian shales and to establishing their potential as a viable energy source.

The technological challenge is to find practical and economic ways to produce this resource. Industry and DOE are presently involved in developing, improving, and evaluating different well stimulation technologies proposed for the exploitation of the gas resources in eastern Kentucky, Ohio and West Virginia. Figure 1-1 shows established production fields in this region.[1] The shales in these areas have long been sources of natural gas with a total production to date of about 3 trillion cubic feet from an area of about 4,076 square miles. For the most part, gas production from the shales has been obtained from wells stimulated with explosives. Since 1965, conventional water based hydraulic fracturing has been used with success.

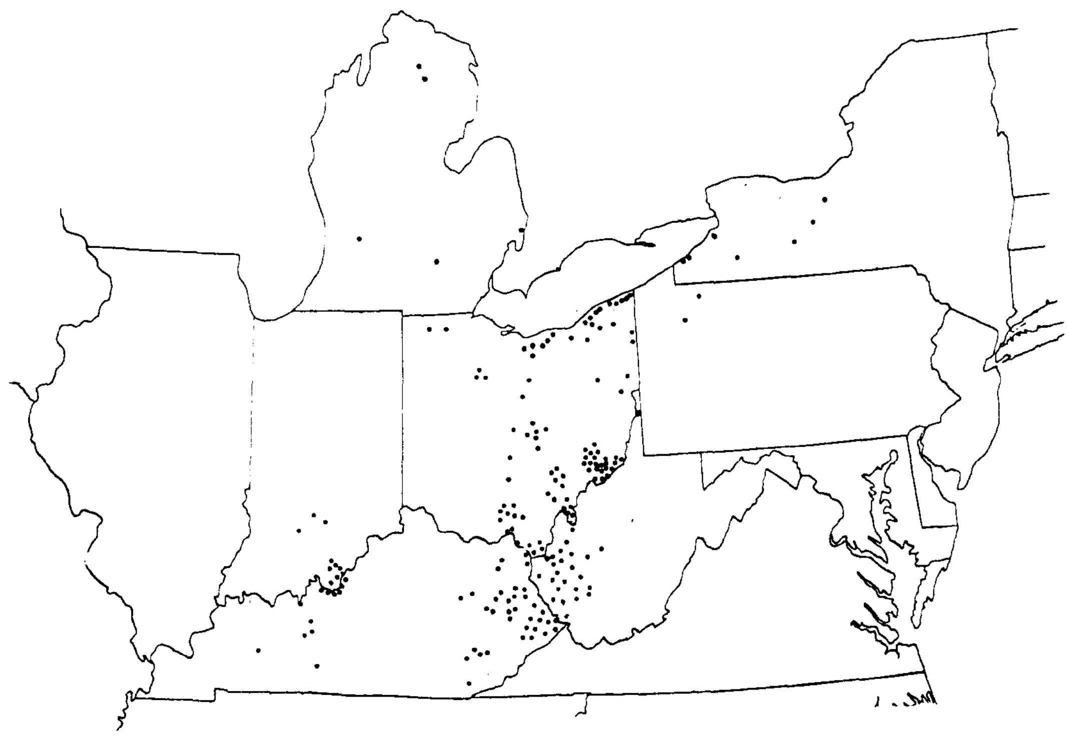

FIGURE 1-1. LOCATION OF THE MAJOR PRODUCING MISSISSIPPIAN-DEVONIAN SHALE GAS FIELDS IN THE EASTERN UNITED STATES

[1] Enhanced Gas Recovery Program Eastern Gas Shales Project Implementation Strategy, November 1977.

In view of the history of successful stimulated and, in some cases, unstimulated production in eastern Kentucky, Ohio, and western West Virginia, the prospect of developing these resources is encouraging. This is especially true for new stimulation methods such as MHF. However, it is evident that new drilling and stimulation strategies will be adopted by those operators exploring and developing the Devonian gas shales only if it pays them to do so. Not only must the economics of new technology such as massive hydraulic fracturing be superior to current technology such as "gel" shooting or "standard" hydraulic fracturing of gas wells in the Appalachian Basin, but the process has to be reliable in order for the operator to justify using it.

1.3 WELL PRODUCTION DECLINE DATA AND STUDY CASES

After stimulation, gas wells in the Appalachian Basin are normally placed on line and the initial open flow of the well measured over a 24-hour period. A definitive relationship exists between the measured initial open flow rate and the well's cumulative gas production as shown in Figure 1-2. Furthermore, it has been the experience of Kentucky-West Virginia Natural Gas Company and Columbia Gas Company of West Virginia that wells with similar open flow rates behave similarly throughout their operating lives. Based on these observations, two sets of generalized well production decline curves were prepared by MERC for this study. The first set, referred to as Scenario A (Figure 1-3), consists of three curves representing open flow rates of 350 MCFD, 200-300 MCFD and 50-175 MCFD. The second set, referred to as Scenario B (Figure 1-4), consists of two curves representing open flow rates of 350 MCFD and 250 MCFD. The generalized production decline curves of these scenarios are based on eight years of actual production data from 25 hydrualically fractured wells in the Devonian Shale (Big Sandy region) of Eastern Kentucky. Decline data beyond eight years were obtained by assuming an exponential production decline model which results in a somewhat conservative (lower than actual) estimate of cumulative production beyond 25 years.

Study cases were analyzed for each of the production decline curves of Scenario A for the three types of operation (utility, independent,

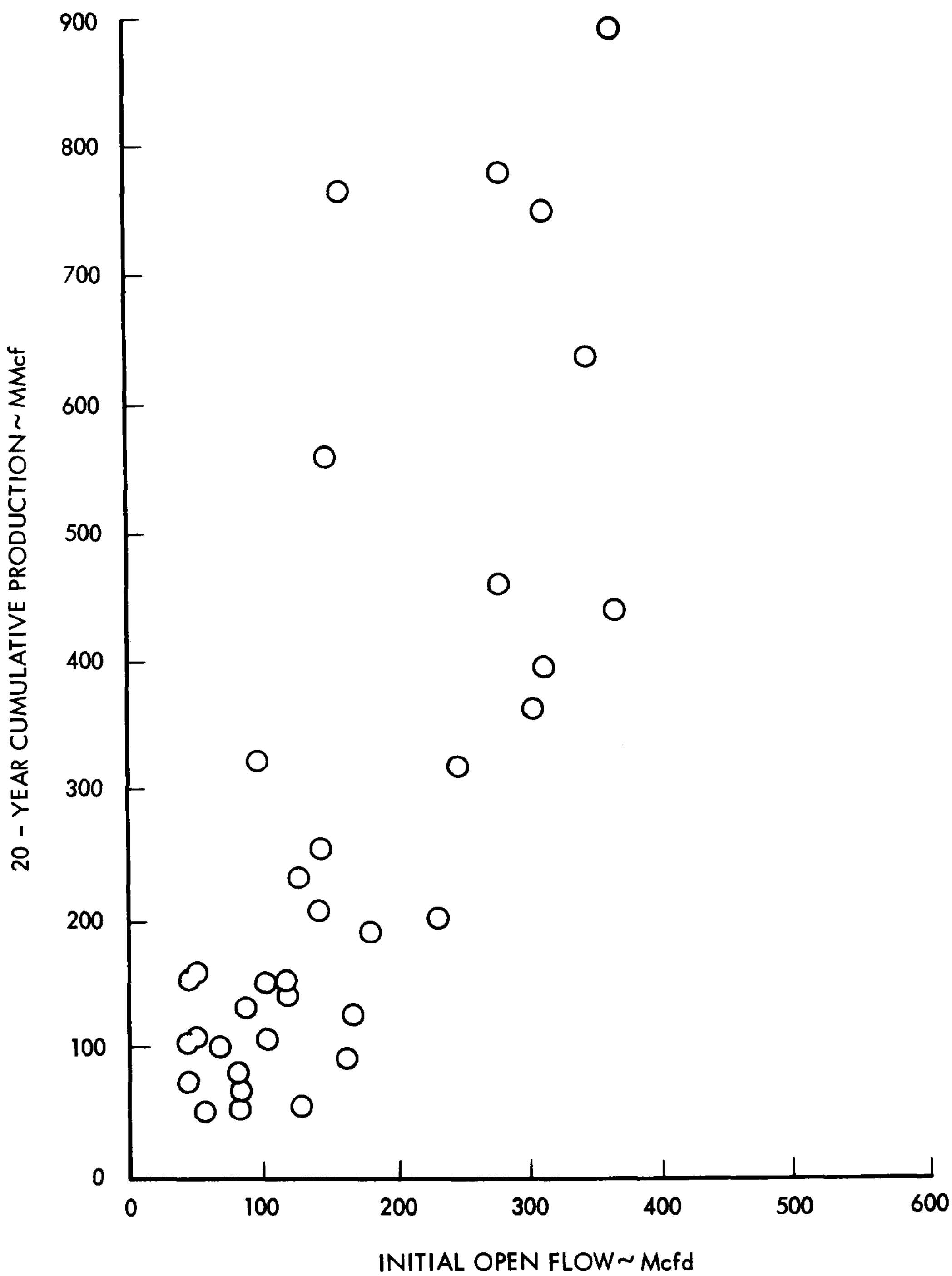

FIGURE 1-2. RELATIONSHIP BETWEEN INITIAL WELL OPEN FLOW RATES AND CUMULATIVE GAS PRODUCTION FROM 35 DEVONIAN SHALE WELLS IN LINCOLN COUNTY, WEST VIRGINIA (COLUMBIA GAS CORPORATION PROJECT REVIEW TO ERDA, 15 MAY 1977)

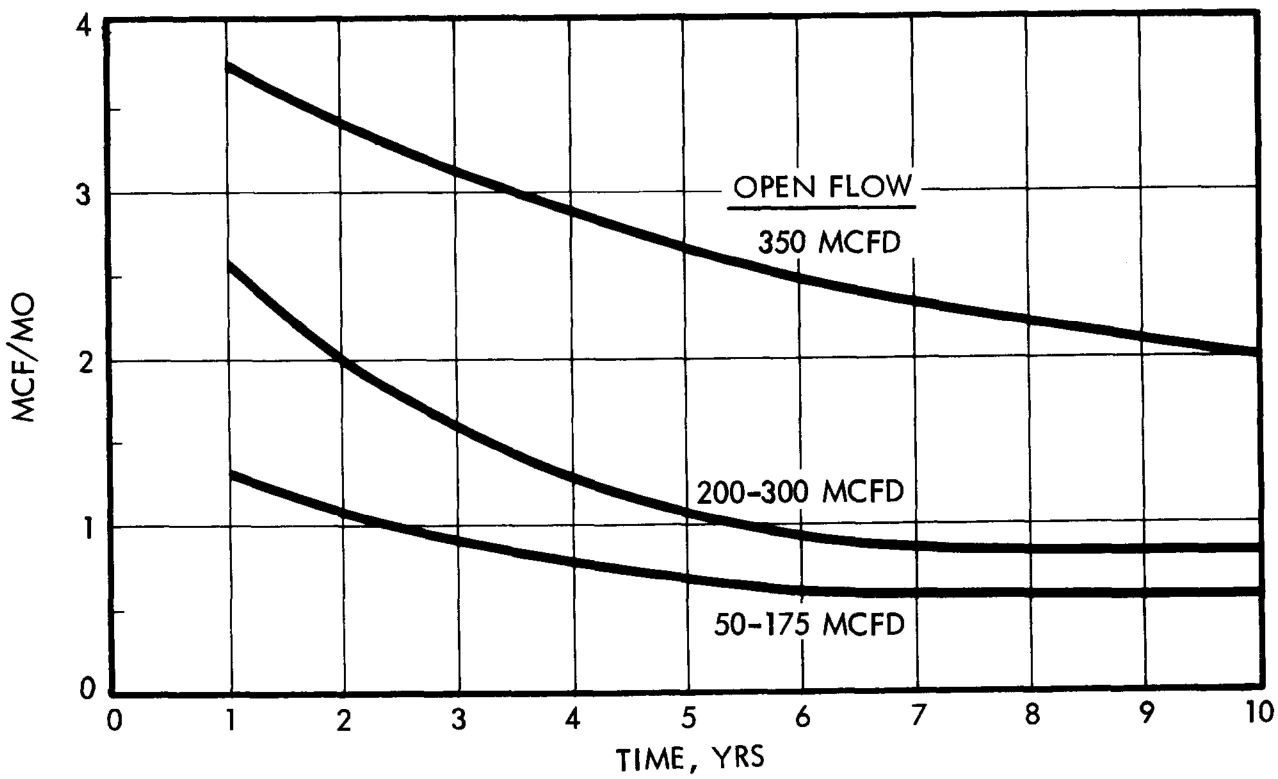

FIGURE 1-3. SCENARIO A - GENERALIZED PRODUCTION DECLINE DATA

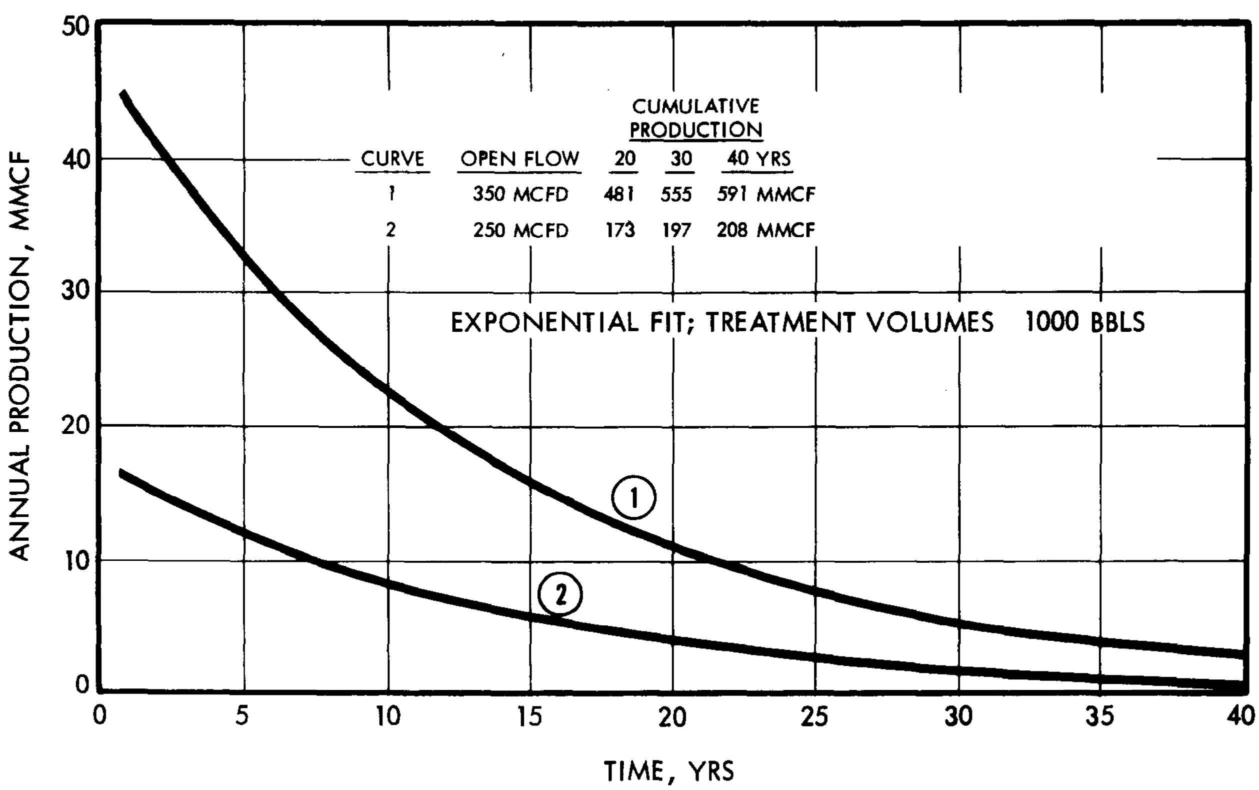

FIGURE 1-4. SCENARIO B - GENERALIZED PRODUCTION DECLINE DATA

self-help) for normal hydraulic fracturing at a cost of $12,000 and MHF at costs of $70,000 and $100,000. Comparable study cases were also analyzed for both production decline curves of Scenario B.

Study results generated with the TRW ECONGAS program are based on the input parameters identified in Section 2.

The numerical results of the study are presented in Section 3 and a discussion of results in Section 4. For convenient reference, the following appendices are also presented.

Appendix A - The ECONGAS Program

Appendix B - Detailed Well Cost Data

Appendix C - Measures of Gas Production Economics Evaluation

Appendix D - Price History of Natural Gas in the Appalachian Basin

2.0 INPUT PARAMETERS FOR THE ECONGAS PROGRAM

The ECONGAS program which was used to generate the numerical results of this study is discussed in detail in Appendix A. The program was run in the mode whereby a desired price is computed based on an input value of return on investment (ROI). Specific input data for the program consist of (1) tablulated well production decline data on a yearly basis for 28 years' well life, (2) detailed well cost data, (3) tax assumption data, and (4) a specified value for ROI. These data, with the exception of item 1, are summarized in Table 2-1.

Tabulated well production data for Scenario A (Figure 1-3) are presented in Table 2-2. Similar data for Scenario B (Figure 1-4) are presented in Table 2-3.

Detailed well cost estimates, obtained from industrial and state agencies through interviews and reviews of internal reports, are presented in Appendix B.

Tax assumptions used as inputs into the ECONGAS model are:

- Income tax rate of 50% to cover U.S. and state taxes.
- Zero production depletion allowance which is consistent with the current treatment of income from natural gas production for producers averaging production for greater than 19.8 MMCFD.
- Intangible cost depletion (Straight line method Eq. 2, Appendix A).
- Ten percent investment tax credit.

No allowance was made in the well cost input data for overhead and dry well costs.

It should be recognized that the ECONGAS computer program treats the costs of drilling in the initial time period (year zero), and treats all other factors, including gas production, depreciation, etc., as starting in the next time period (year one). For short initial time periods of drilling, the prices indicated to yield the required annual rate of return could be slightly overstated.

TABLE 2-1. COST AND PRODUCTION DATA INPUT INTO THE ECONGAS PROGRAM FOR THREE DIFFERENT TYPES OF OPERATORS AND TWO PRODUCTION DECLINE SCENARIOS A AND B.

INPUT PARAMETERS	UTILITY	INDEPENDENT	SELF-HELP
1. Price Annual Increase $(Paincr) (1) Interstate (2) Intrastate	 0.04 0.00	 0.04 0.00	 N/A 0.00
2. Production Exponential Decay Investment, % (K)		SCENARIO A Q_1 350 MCFD* Q_2 200-300 MCFD* Q_3 50-175 MCFD*	SCENARIO B Q_4 350 MCFD* Q_5 250 MCFD*
3. Annual Rate of Return on Investment, % (R)	6,10,20	10,15,20	10,15,20
4. Income Tax Retention Rate, % (u)	50	50	50
5. Intangible Costs Which Must Be Cost Depleted, $ (EO)	160	160	160
6. Tangible Costs Which Must Be Depreciated Factor, $ (DO) Include:			
(1) Hydraulic Fracturing a. $12,000	 18,500	 16,754	 18,156
(2) Massive Hydraulic Frac. a. $70,000 b. $100,000	 30,100 36,100	 32,240 40,250	 33,642 41,652

*Initial well open flow rates.

TABLE 2-1. COST AND PRODUCTION DATA INPUT INTO THE ECONGAS PROGRAM FOR THREE DIFFERENT TYPES OF OPERATORS AND TWO PRODUCTION DECLINE SCENARIOS A AND B. (Continued)

INPUT PARAMETERS	UTILITY	INDEPENDENT	SELF-HELP
7. All Well Preparation Cost That Can Be Expensed, $ (WO)			
(1) Hydraulic Fract.			
a. $12,000	74,000	45,996	49,844
(2) Massive Hydraulic Fract.			
a. $70,000	119,900	88,510	92,357
b. $100,000	144,400	110,500	114,340
8. Operating and Maintenance Expense, $/yr. (ØM Base)	1,000	1,200	1,000
9. Inflation rate For O&M Expenses, % (ØMINFL)	8	8	8
10. Investment Tax Credit Rate, % (CREDRAT)	10	10	10
11. Number of Years of Operation (N)	28	28	28
12. Average Initial Annual Line Flow Rate MCF/YEAR (QA)	NA	NA	NA
13. Depreciation Period (Straight Line Method) (LIFEDPR)	28	28	28

TABLE 2-1. COST AND PRODUCTION DATA INPUT INTO THE ECONGAS PROGRAM FOR THREE DIFFERENT TYPES OF OPERATORS AND TWO PRODUCTION DECLINE SCENARIOS A AND B. (Continued)

INPUT PARAMETERS	UTILITY	INDEPENDENT	SELF-HELP
14. Percentage of Revenue Paid to Lessor (Royalty) 9(DELTA)	12.5	0, 12.5	0, 12.5
15. Stimulation Costs, $			
(1) Hydraulic Fracturing	12,000	12,000	12,000
(2) Massive Hydraulic Fracturing	70,000 100,000	70,000 100,000	70,000 100,000
16. Average Depth of Well, Ft.	3,500	3,500	3,500
17. Average Contract Drilling Costs, $/Ft.	11.50	7.25	8.00
18. Drilling Cost for 3,500 Ft. Well, (17 X 18), $	40,250	25,375	28,000
19. Tangibles % of Each Well Cost, %	20	26.7	26.7
20. Total Well Cost Based on Rule of Thumb That Completing The Well Is As Expensive As Drilling Plus The Stimulation Costs, $			
(1) Hydraulic Fractured Well. Drill - compl. - stim. a. $12,000	92,500	62,750	68,000
(2) Massive Hydraulic Fracturing, $, Drill - compl. - stim.			
a. $70,000	150,000	120,750	126,000
b. $100,000	180,500	150,750	156,000

TABLE 2-2. SCENARIO A - TABULATION OF THE AVERAGE GAS WELL ANNUAL PRODUCTION RATES FOR INPUT INTO THE ECONGAS PROGRAM.

CLASS INITIAL RATES YEAR	Q_1 350 MCFD MMCF/YR.	Q_2 200-300 MCFD MMCF/YR.	Q_3 50-175 MCFD MMCF/YR.
1	45.00	30.60	15.60
2	41.40	24.00	13.20
3	37.80	19.80	11.04
4	33.60	15.60	9.84
5	31.80	12.60	8.64
6	29.40	11.28	7.80
7	27.60	10.56	7.20
8	26.40	10.20	6.96
9	25.20	9.96	6.72
10	24.00	9.84	6.48
11	23.00	8.80	6.35
12	22.30	7.70	6.14
13	21.30	6.60	5.93
14	20.50	5.50	5.72
15	19.50	4.40	5.51
16	18.70	3.30	5.30
17	17.60	2.30	5.09
18	16.70	2.30	4.89
19	15.70	2.30	4.68
20	14.80	2.30	4.47
21	13.80	2.30	4.26
22	13.30	2.30	4.05
23	12.40	2.30	3.84
24	11.40	2.30	3.63
25	10.50	2.30	3.42
26	9.60	2.30	3.21
27	8.70	2.30	3.00
28	8.70	2.30	2.79

TABLE 2-3. SCENARIO B - TABULATION OF THE AVERAGE GAS WELL ANNUAL PRODUCTION RATES FOR INPUT INTO THE ECONGAS PROGRAM.

CLASS INITIAL RATES YEAR	Q_4 350 MCFD MMCF/YR.	Q_5 250 MCFD MMCF/YR.
1	44.4	16.9
2	41.0	15.5
3	37.8	14.3
4	35.3	13.2
5	32.8	12.2
6	30.6	11.2
7	28.7	10.3
8	26.5	9.5
9	24.6	8.8
10	22.8	8.0
11	21.3	7.4
12	19.9	6.9
13	18.4	6.2
14	17.0	5.8
15	15.9	5.3
16	14.7	5.0
17	13.6	4.6
18	12.7	4.2
19	11.9	3.9
20	11.0	3.4
21	10.2	3.2
22	9.4	3.0
23	8.9	2.8
24	8.2	2.6
25	7.7	2.4
26	7.0	2.3
27	6.6	2.2
28	6.1	2.1

3.0 STUDY RESULTS

3.1 ECONGAS DESIRED PRICE DATA

The numerical data generated with the ECONGAS program are presented in Tables 3-2 through 3-7. For easy reference, Table 3-1 presents a summary of the well cost assumptions for each operator model from Table 2-1. Tables 3-2 through 3-4 are based on input data involving the Scenario A production decline curves. Tables 3-5 through 3-7 are based on Scenario B production decline data. The utility model cases considered annual ROI inputs of 6, 10 and 20 percent whereas the independent and self-help cases considered 10, 15 and 20.

Experience has shown that six percent is a typical ROI for utility drilling operations and was therefore incorporated in the study. The 10 and 20 percent values for the utility model can be compared directly with those same ROI values for the independent and self-help models. The 10 percent figure is believed to be the lowest value which would ever be considered by an independent operation whereas ROI may have little significance for a self-help operation, depending on the relative cost of produced gas to his overall cost of doing business. Consequently the 10, 15 and 20 percent values for the self-help cases were arbitrarily selected for comparison with the independent and utility examples.

3.1.1 Scenario A Production Decline Examples

The utility and independent model data presented in Tables 3-2 and 3-3 respectively consider interstate pricing with an assumed annual price escalation of \$0.04/MCF and intrastate pricing with an assumed fixed price. The data presented for the independent and self-help models in Tables 3-3 and 3-4 consider royalty payments to be zero in one case and a payment of 12.5 percent for another case. To give an indication of price sensitivity to changes in percentage royalty payment for the utility mode, a 6 percent royalty payment example is included in Table 3-2 for the 350 MCFD initial open flow production decline curve and interstate pricing (i.e., \$0.04/MCF annual price escalation).

TABLE 3-1. SUMMARY OF ECONGAS WELL COST ASSUMPTIONS FOR EACH OPERATOR MODEL

COST PARAMETER	OPERATOR MODEL, COSTS IN DOLLARS		
	UTILITY	INDEPENDENT	SELF-HELP
TANGIBLE COST (DEPRECIATED):			
• Hydraulic Frac @ $12,000	18,500	16,754	18,156
• MHF @:			
(a) $70,000	30,100	32,240	33,642
(b) $100,000	36,100	40,250	41,652
WELL PREPARATION COST (EXPENSED):			
• Hydraulic Frac @ $12,000	74,000	45,996	49,844
• MHF @:			
(a) $70,000	119,900	88,510	92,357
(b) $100,000	144,400	110,500	114,340
TOTAL WELL COST:			
• Hydraulic Frac @ $12,000	92,500	62,750	68,000
• MHF @:			
(a) $70,000	150,000	120,750	126,000
(b) $100,000	180,500	150,750	156,000

TABLE 3-2. INITIAL GAS PRICE ($/MCF) FOR UTILITY MODEL WITH SCENARIO A PRODUCTION DECLINE DATA

		FRACTURE TYPE								
		$12K HF			$70K MHF			$100K MHF		
SPECIFIED ROI, %		6	10	20	6	10	20	6	10	20
INTERSTATE										
Royalty = 12.5%	Q_1*	0.081	0.229	0.579	0.283	0.501	1.032	0.390	0.646	1.271
Yearly Price Increase = $0.04	Q_2	0.795	0.952	1.398	1.275	1.555	2.295	1.529	1.875	2.769
	Q_3	1.167	1.510	2.417	1.855	2.432	3.917	2.220	2.920	4.711
Royalty = 6.0% Yearly Price Increase = $0.04	Q_1	0.076	0.213	0.536	0.264	0.465	0.956	0.367	0.606	1.188
INTRASTATE										
Royalty = 12.5%	Q_1	0.448	0.532	0.788	0.650	0.804	1.240	0.757	0.949	1.480
Yearly Price Increase = $0.00	Q_2	1.064	1.179	1.563	1.544	1.782	2.460	1.798	2.101	2.935
	Q_3	1.527	1.803	2.614	2.215	2.725	4.114	2.580	3.213	4.908

*Production Decline Curve Used (Figure 1-3): Q_1 - Upper Curve
Q_2 - Middle Curve
Q_3 - Lower Curve

TABLE 3-3. INITIAL GAS PRICE ($/MCF) FOR INDEPENDENT MODEL WITH SCENARIO A PRODUCTION DECLINE DATA

		FRACTURE TYPE								
		$12K HF			$70K MHF			$100 MHF		
SPECIFIED ROI, %		10	15	20	10	15	20	10	15	20
INTERSTATE										
Royalty = 12.5%	Q_1*	0.116	0.250	0.377	0.399	0.627	0.850	0.545	0.823	1.095
Yearly Price Increment = $0.04	Q_2	0.702	0.841	0.995	1.327	1.626	1.934	1.651	2.032	2.420
	Q_3	1.126	1.429	1.744	2.083	2.696	3.315	2.578	3.351	4.127
Royalty = 0%	Q_1	0.102	0.218	0.330	0.349	0.549	0.744	0.477	0.720	0.958
Yearly Price Increment = $0.04	Q_2	0.614	0.736	0.871	1.161	1.423	1.693	1.445	1.778	2.118
	Q_3	0.985	1.250	1.526	1.823	2.359	2.900	2.256	2.932	3.611
INTRASTATE										
Royalty = 12.5%	Q_1	0.419	0.497	0.585	0.702	0.874	1.059	0.848	1.070	1.304
Yearly Price Increment = $0.00	Q_2	0.928	1.031	1.161	1.554	1.816	2.100	1.878	2.222	2.586
	Q_3	1.419	1.665	1.941	2.377	2.932	3.512	2.872	3.587	4.324
Royalty = 0%	Q_1	0.367	0.434	0.512	0.614	0.765	0.926	0.742	0.936	1.141
Yearly Price Increment = $0.00	Q_2	0.812	0.902	1.016	1.360	1.589	1.837	1.643	1.944	2.262
	Q_3	1.242	1.457	1.699	2.080	2.565	3.073	2.513	3.139	3.784

*Production Decline Curve Used (Figure 1-3): Q_1 - Upper Curve
Q_2 - Middle Curve
Q_3 - Lower Curve

TABLE 3-4. INITIAL GAS PRICE ($/MCF) FOR SELF-HELP MODEL WITH SCENARIO A PRODUCTION DECLINE DATA

		FRACTURE TYPE								
		$12K HF			$70K MHF			$100K MHF		
SPECIFIED ROI, %		10	15	20	10	15	20	10	15	20
INTRASTATE										
Royalty = 12.5%	Q_1*	0.426	0.516	0.616	0.708	0.894	1.090	0.855	1.090	1.335
Yearly Price Increment = $0.00	Q_2	0.943	1.072	1.222	1.569	1.857	2.161	1.893	2.263	2.647
	Q_3	1.443	1.731	2.044	2.400	2.998	3.615	2.895	3.653	4.427
Royalty = 0%	Q_1	0.373	0.452	0.539	0.620	0.782	0.954	0.748	0.953	1.168
Yearly Price Increment = $0.00	Q_2	0.825	0.938	1.069	1.373	1.625	1.891	1.656	1.980	2.316
	Q_3	1.262	1.515	1.789	2.100	2.623	3.163	2.533	3.197	3.873

*Production Decline Curve Used (Figure 1-3): Q_1 - Upper Curve

Q_2 - Middle Curve

Q_3 - Lower Curve

TABLE 3-5. INITIAL GAS PRICE ($/MCF) FOR UTILITY MODEL WITH SCENARIO B PRODUCTION DECLINE DATA

		FRACTURE TYPE								
		$12K HF			$70K MHF			$100K MHF		
SPECIFIED ROI, %		6	10	20	6	10	20	6	10	20
INTERSTATE										
Royalty = 12.5%	Q_4*	0.134	0.267	0.594	0.346	0.548	1.050	0.459	0.697	1.292
Yearly Price Increase = $0.04	Q_5	0.979	1.232	1.947	1.567	2.002	3.177	1.878	2.409	3.828
INTRASTATE										
Royalty = 12.5%	Q_4	0.472	0.550	0.795	0.684	0.831	1.252	0.797	0.980	1.493
Yearly Price Increase = $0.00	Q_5	1.303	1.505	2.143	1.891	2.274	3.373	2.202	2.682	4.024

*Production Decline Curve Used (Figure 1-4): Q_4 - Upper Curve
Q_5 - Lower Curve

TABLE 3-6. INITIAL GAS PRICE ($/MCF) FOR INDEPENDENT MODEL WITH SCENARIO B PRODUCTION DECLINE DATA

		FRACTURE TYPE								
		$12K HF			$70K MHF			$100 MHF		
SPECIFIED ROI, %		10	15	20	10	15	20	10	15	20
INTERSTATE										
Royalty = 12.5%	Q_4*	0.150	0.270	0.389	0.442	0.655	0.867	0.593	0.854	1.114
Yearly Price Increment = $0.04	Q_5	0.912	1.143	1.396	1.711	2.186	2.683	2.124	2.726	3.349
Royalty = 0%	Q_4	0.131	0.237	0.340	0.386	0.573	0.758	0.519	0.747	0.975
Yearly Price Increment = $0.04	Q_5	0.798	1.000	1.221	1.497	1.913	2.348	1.858	2.385	2.931
INTRASTATE										
Royalty = 12.5%	Q_4	0.433	0.505	0.591	0.725	0.890	1.069	0.876	1.089	1.316
Yearly Price Increment = $0.00	Q_5	1.184	1.370	1.592	1.983	2.413	2.879	2.396	2.953	3.546
Royalty = 0%	Q_4	0.379	0.442	0.517	0.634	0.779	0.935	0.766	0.953	1.151
Yearly Price Increment = $0.00	Q_5	1.036	1.199	1.393	1.735	2.112	2.519	2.097	2.584	3.102

*Production Decline Curve Used (Figure 1-4): Q_4 - Upper Curve
Q_5 - Lower Curve

TABLE 3-7. INITIAL GAS PRICE ($/MCF) FOR SELF-HELP MODEL WITH SCENARIO B PRODUCTION DECLINE DATA

		FRACTURE TYPE								
		$12K HF			$70K MHF			$100K MHF		
SPECIFIED ROI, %		10	15	20	10	15	20	10	15	20
INTRASTATE										
Royalty = 12.5%	Q_4*	0.440	0.526	0.622	0.732	0.910	1.100	0.883	1.109	1.347
Yearly Price Increment = $0.00	Q_5	1.204	1.425	1.676	2.003	2.468	2.964	2.416	3.008	3.630
Royalty = 0%	Q_4	0.385	0.460	0.544	0.641	0.796	0.962	0.773	0.971	1.179
Yearly Price Increment = $0.00	Q_5	1.053	1.247	1.467	1.752	2.160	2.593	2.114	2.632	3.176

*Production Decline Curve Used (Figure 1-4): Q_4 - Upper Curve
Q_5 - Lower Curve

3.1.2 Scenario B Production Decline Examples

The data presented for Scenario B in Tables 3-5 through 3-7 correspond to the Scenario A data presented in Tables 3-2 through 3-4, respectively. A comparison of corresponding examples from Scenario A and Scenario B provides an indication of variations in desired price to variations in the respective well production decline characteristics.

3.2 INVESTMENT PAYOUT RESULTS

Payout time calculations were performed for the three operation models (utility, independent and self-help) for the Scenario B production decline data at the desired prices generated by the ECONGAS program. These calculations are summarized in Tables 3-8 through 3-10, respectively, for the utility, independent and self-help models. Payout times were determined only for the normal hydraulic fracturing and $70,000 MHF cases. As shown by comparing the hydraulic fracturing and MHF data in Tables 3-8 through 3-10, the investment payout time is relatively insensitive to large changes in total investment for a given ROI. Therefore, payout times for the $100,000 MHF case will not differ appreciably from those for the $70,000 MHF case for the same ROI values.

3.3 PROFIT/INVESTMENT RESULTS

Profit/investment ratio (PIR) calculations were performed for the utility and independent models with the Scenario B production decline curves and the prices obtained from the ECONGAS program; these results are presented in Tables 3-11 and 3-12, respectively, for the utility and independent models. Calculations of PIR for the self-help model were not performed because the data trend (essentially zero) from the utility to independent operations indicates virtually the same PIR values for the self-help model. In addition, the PIR values, like the payout time values in Section 3.2, are highly insensitive to the size of investment for a given value of ROI. Thus, the PIR's obtained for the utility and independent models will be essentially the same for the self-help model for the same values of ROI.

TABLE 3-8. PAYOUT TIMES FOR UTILITY MODEL WITH SCENARIO B PRODUCTION DECLINE DATA

		FRACTURE TYPE					
		$12K HF			$70K MHF		
SPECIFIED ROI %		6	10	20	6	10	20
INTERSTATE							
Royalty, 12.5%	Q_4*	11.48	8.25	4.51	11.18	7.93	4.39
Yearly Price Increase = $0.04	Q_5	8.92	6.84	4.09	9.36	6.94	4.07
INTERSTATE							
Royalty, 12.5%	Q_4	7.94	6.37	3.98	8.82	6.71	4.04
Yearly Price Increase = $0.00	Q_5	7.60	6.15	3.98	8.48	6.50	3.95

*Production Decline Curve Used (Figure 1-4): Q_4 - Upper Curve
Q_5 - Lower Curve

TABLE 3-9. PAYOUT TIMES FOR INDEPENDENT MODEL WITH SCENARIO B PRODUCTION DECLINE DATA

		FRACTURE TYPE					
		$12K HF			$70K MHF		
SPECIFIED ROI, %		10	15	20	10	15	20
INTERSTATE							
Royalty = 12.5%	Q_4*	8.36	6.06	4.65	7.93	5.71	4.41
Yearly Price Increase = $0.04	Q_5	6.71	5.09	4.01	6.73	5.07	4.04
Royalty = 0%	Q_4	8.36	6.06	4.65	7.96	5.71	4.41
Yearly Price Increase = $0.04	Q_5	6.71	5.09	4.07	6.72	5.07	4.04
INTRASTATE							
Royalty = 12.5%	Q_4	5.88	4.74	3.88	6.52	5.00	4.00
Yearly Price Increase = $0.00	Q_5	6.00	4.70	3.83	6.35	4.86	3.91
Royalty = 0%	Q_4	5.88	4.74	3.88	6.52	5.00	4.00
Yearly Price Increase = $0.00	Q_5	6.00	4.70	3.83	6.36	4.86	3.91

*Production Decline Curve Used (Figure 1-4): Q_4 - Upper Curve

Q_5 - Lower Curve

TABLE 3-10. PAYOUT TIMES FOR SELF-HELP MODEL WITH SCENARIO B PRODUCTION DECLINE DATA

		FRACTURE TYPE					
		$12K HF			$70K MHF		
SPECIFIED ROI, %		10	15	20	10	15	20
INTERSTATE							
Royalty = 12.5%	Q_4*	5.70	4.78	3.92	6.40	5.01	4.02
Yearly Price Increase = $0.00	Q_5	5.48	4.64	3.84	6.18	4.88	3.93
INTRASTATE							
Royalty = 0%	Q_4	5.70	4.78	3.92	6.40	5.01	4.02
Yearly Price Increase = $0.00	Q_5	5.48	4.64	3.84	6.18	4.88	3.93

*Production Decline Curve Used (Figure 1-4): Q_4 - Upper Curve

Q_5 - Lower Curve

TABLE 3-11. PROFIT/INVESTMENT RATIOS FOR UTILITY MODEL WITH SCENARIO B PRODUCTION DECLINE DATA.

		FRACTURE TYPE					
		$12K HF			$70K MHF		
SPECIFIED ROI, %		6	10	20	6	10	20
INTERSTATE							
Royalty, 12.5%	Q_4*	0.81	1.38	2.78	0.76	1.29	2.62
Yearly Price Increase = $0.04	Q_5	0.43	0.81	1.90	0.51	0.92	2.02
INTERSTATE							
Royalty, 12.5%	Q_4	0.30	0.63	1.68	0.44	0.83	1.94
Yearly Price Increase = $0.00	Q_5	0.26	0.56	1.53	0.40	0.76	1.79

*Production Decline Curve Used (Figure 1-4): Q_4 - Uper Curve

Q_5 - Lower Curve

TABLE 3-12. PROFIT/INVESTMENT RATIOS FOR UTILITY MODEL WITH SCENARIO B PRODUCTION DECLINE DATA

		FRACTURE TYPE					
		$12K HF			$70K MHF		
SPECIFIED ROI, %		10	15	20	10	15	20
INTERSTATE							
Royalty = 12.5%	Q_4*	1.36	2.08	2.78	1.25	1.91	2.56
Yearly Price Increase = $0.04	Q_5	0.79	1.23	1.69	0.80	1.24	1.70
Royalty = 0%	Q_4	1.36	2.08	2.78	1.25	1.91	2.56
Yearly Price Increase = $0.04	Q_5	0.79	1.23	1.69	0.80	1.24	1.70
INTRASTATE							
Royalty = 12.5%	Q_4	0.37	0.81	1.32	0.73	1.246	1.80
Yearly Price Increase = $0.00	Q_5	0.64	1.03	1.45	0.72	1.131	1.56
Royalty = 0%	Q_4	0.37	0.81	1.32	0.73	1.246	1.80
Yearly Price Increase = $0.00	Q_5	0.64	1.03	1.45	0.72	1.131	1.56

*Production Decline Curve Used (Figure 1-4): Q_4 - Upper Curve

Q_5 - Lower Curve

4.0 DISCUSSION OF RESULTS

4.1 ECONOMICALLY VIABLE MHF DRILLING OPTIONS

The results of this report, presented in Section 3, show that, under the assumed well production and operation conditions considered, certain attractive economic possibilities involving MHF stimulation technology do exist. These are based on the economic factors (i.e., desired wellhead price, payout time and PIR) which would presumably be considered by the private sector prior to drilling for Devonian Shale gas in the Appalachian Basin. A more detailed discussion of these factors is presented in Appendix C. The consideration of economic viability of the various hydraulic fracturing and MHF models presented in Section 3 is based on the following:

- Desired Price Based on Specified Discounted Cash Flow ROI Values - A comparison is made of the desired price with the current price structure within the Appalachian Basin. The current wellhead ceiling price for interstate gas production is $1.42 per MCF, and is adjusted for gathering, tax rebate, quarterly escalator and BTU content in the Appalachian Basin.* The current maximum intrastate prices in the Appalachian Basin are on the order of $2.25, especially in Eastern Kentucky and West Virginia. The current interstate ceiling price and the $2.25 intrastate price were assumed to evaluate the utility and independent models. A winter spot price of $3.00 was assumed to evaluate the self-help model. A detailed discussion of price structure is presented in Appendix D.

- Required Investment Payout Time - It was assumed that investment payout times in excess of 6 years would be unacceptable for utility and self-help operations and values in excess of 4 years would be unacceptable for independent operations. Payout time considerations are discussed in Appendix C.

- Profit/Investment Ratio (PIR) - A general risk guideline for drilling ventures by utilities and independents is that the estimated PIR should be greater than unity (Appendix C). This guideline was assumed as a criterion. No PIR criterion was used for the self-help model.

The above economic factors were used to evaluate the hydraulic fracturing and MHF options for the Scenario B well production decline

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*Quarterly escalator is the only adjustment considered in the study.

characteristics. The evaluation results are presented in Tables 4-1, 4-2 and 4-3 respectively for the utility, independent and self-help models. The checked boxes in the tables represent the options which would be economically viable in accordance with the specified evaluation criteria. With the exception of four examples in Table 3-7 for which the $100,000 MHF prices exceed $3.00, the checked options presented in Tables 4-1 through 4-3 for the $70,000 MHF options also apply for the comparable $100,000 MHF options.

4.2 PRICE SENSTIVITY TO CHANGES IN ROI, WELL PRODUCTIVITY AND WELL COST

In order to illustrate the effect on desired wellhead gas price (as calculated by ECONGAS) to changes in specified ROI, well production decline characteristics and well cost data, the following sets of data are presented in Figures 4-1 and 4-2.

- Figure 4-1 - Desired wellhead gas price is plotted as a function of specified ROI for the utility model interstate pricing ($0.04 annual escalator) cases from Table 3-2 using the 12.5% royalty amount and Scenario A production decline curves (Q_1, Q_2, Q_3).
- Figure 4-2 - Desired wellhead gas price is plotted as a function of specified ROI for the utility model cases from Table 3-5 using the better production decline curve (Q_4) from Scenario B.

The data in Figure 4-1 show that desired wellhead price is extremely sensitive to well productivity characteristics at all values of ROI and that price sensitivity to ROI changes increases with decreased well productivity. Figure 4-2 data show that desired wellhead price is relatively insensitive to initial well cost for well production decline characteristics represented by curve Q_4. The relationship of specified ROI to desired wellhead price is shown to be essentially linear over the range of data considered in this study.

4.3 ECONOMIC SUMMARY

Based on the results presented in Section 3, the following observations can be stated.

- Massive hydraulic fracturing is economically viable under certain assumed well production decline and economic conditions for the utility, independent and self-help models considered herein.

TABLE 4-1. SCENARIO B - UTILITY MODEL - ECONOMIC RATING OF HYDRAULIC FRACTURING AND MASSIVE HYDRAULIC FRACTURING STIMULATION PROJECTS

		FRACTURE TYPE					
		$12K HF			$70K MHF		
SPECIFIED ROI, %		6	10	20	6	10	20
INTERSTATE Royalty, 12.5%	Q_4*			√ **		√	√
Yearly Price Increase = $0.04	Q_5						
INTERSTATE Royalty, 12.5%	Q_4			√			√
Yearly Price Increase = $0.00	Q_5			√			

*Production Decline Curve Used (Figure 1-4): Q_4 - Upper Curve
Q_5 - Lower Curve

**Economically Viable Options: Acceptable Price + Payout Time $\leq$ 6 Years + PIR > 1.0.

TABLE 4-2. SCENARIO B - INDEPENDENT MODEL - ECONOMIC RATING OF HYDRAULIC FRACTURING AND MASSIVE HYDRAULIC FRACTURING STIMULATION PROJECTS

		FRACTURE TYPE					
		$12K HF			$70K MHF		
SPECIFIED ROI, %		10	15	20	10	15	20
INTERSTATE							
Royalty = 12.5%	Q_4*			?***			√**
Yearly Price Increase = $0.04	Q_5			√			
Royalty = 0%	Q_4			?			√
Yearly Price Increase = $0.04	Q_5			√			
INTERSTATE							
Royalty = 12.5%	Q_4			√			√
Yearly Price Increase = $0.00	Q_5			√			
Royalty = 0%	Q_4			√			√
Yearly Price Increase - $0.00	Q_5			√			

*Production Decline Curve Used (Figure 1-4): Q_4 - Upper Curve
Q_5 - Lower Curve

**Economically Viable Options: Acceptable Price + Payout Time $\leq$ 4 Years + PIR > 1.0.

***Marginal Payment Time; Otherwise Economically Viable.

TABLE 4-3. SCENARIO B - SELF-HELP MODEL - ECONOMIC RATING OF HYDRAULIC AND MASSIVE HYDRAULIC FRACTURING STIMULATION PROJECTS

		FRACTURE TYPE					
		\$12K HF			\$70K MHF		
SPECIFIED ROI, %		10	15	20	10	15	20
INTRASTATE Royalty = 12.5%	Q_4*	√ **	√	√	√	√	√
Yearly Price Increase = NA	Q_5	√	√	√	√	√	√
INTRASTATE Royalty = 0%	Q_4	√	√	√	√	√	√
Yearly Price Increase = NA	Q_5	√	√	√	√	√	√

*Production Decline Curve Used (Figure 1-4): Q_4 - Upper Curve
Q_5 - Lower Curve

**Economically Viable Options: Acceptable Price + Payout Time $\leq$ 6 Years + PIR > 1.0.

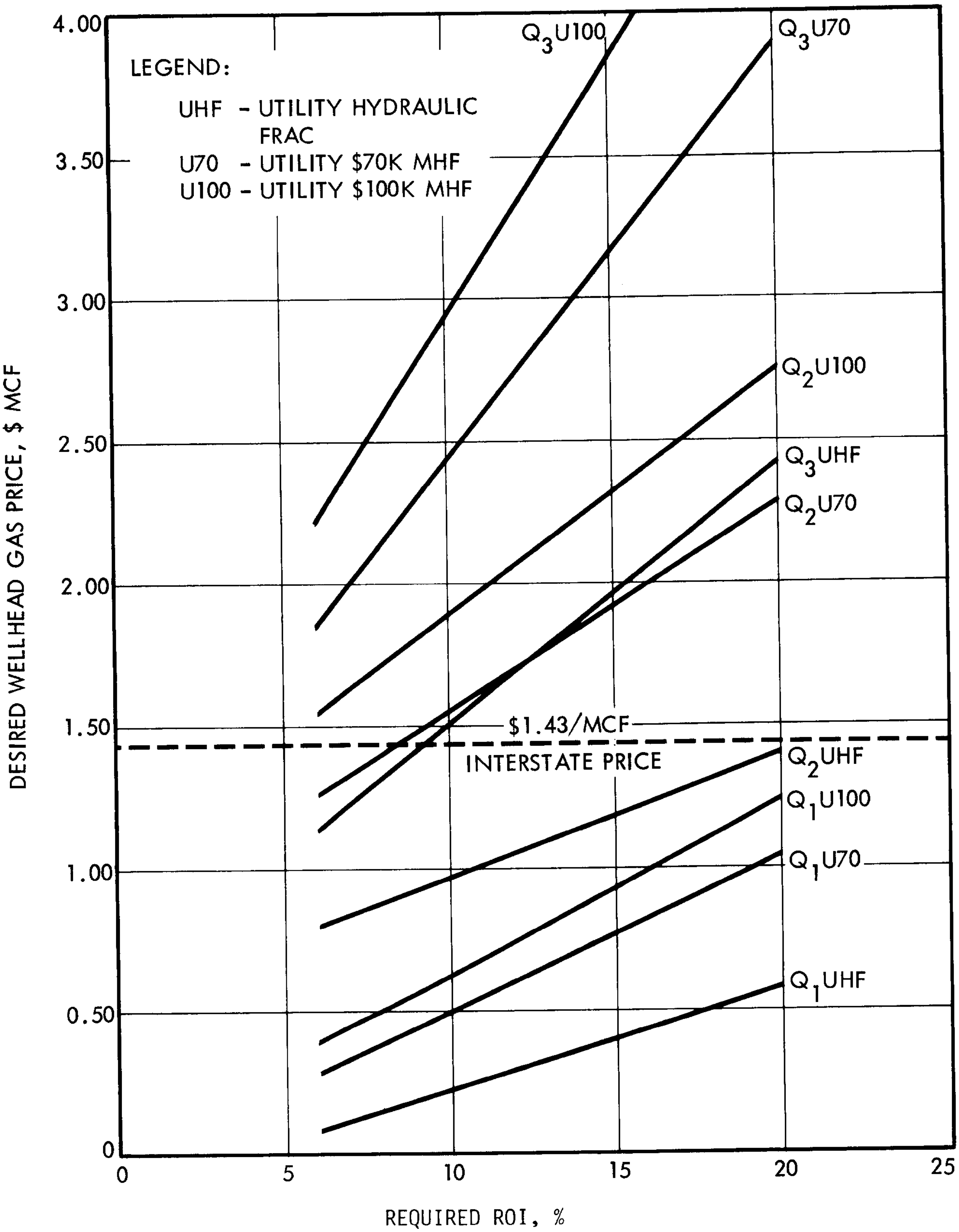

FIGURE 4-1. DESIRED WELLHEAD PRICE AS A FUNCTION OF ROI FOR SELECTED UTILITY MODEL CASES FROM TABLE 3-2 (SCENARIO A PLUS 12.5% ROYALTY PLUS $0.04 ESCALATOR)

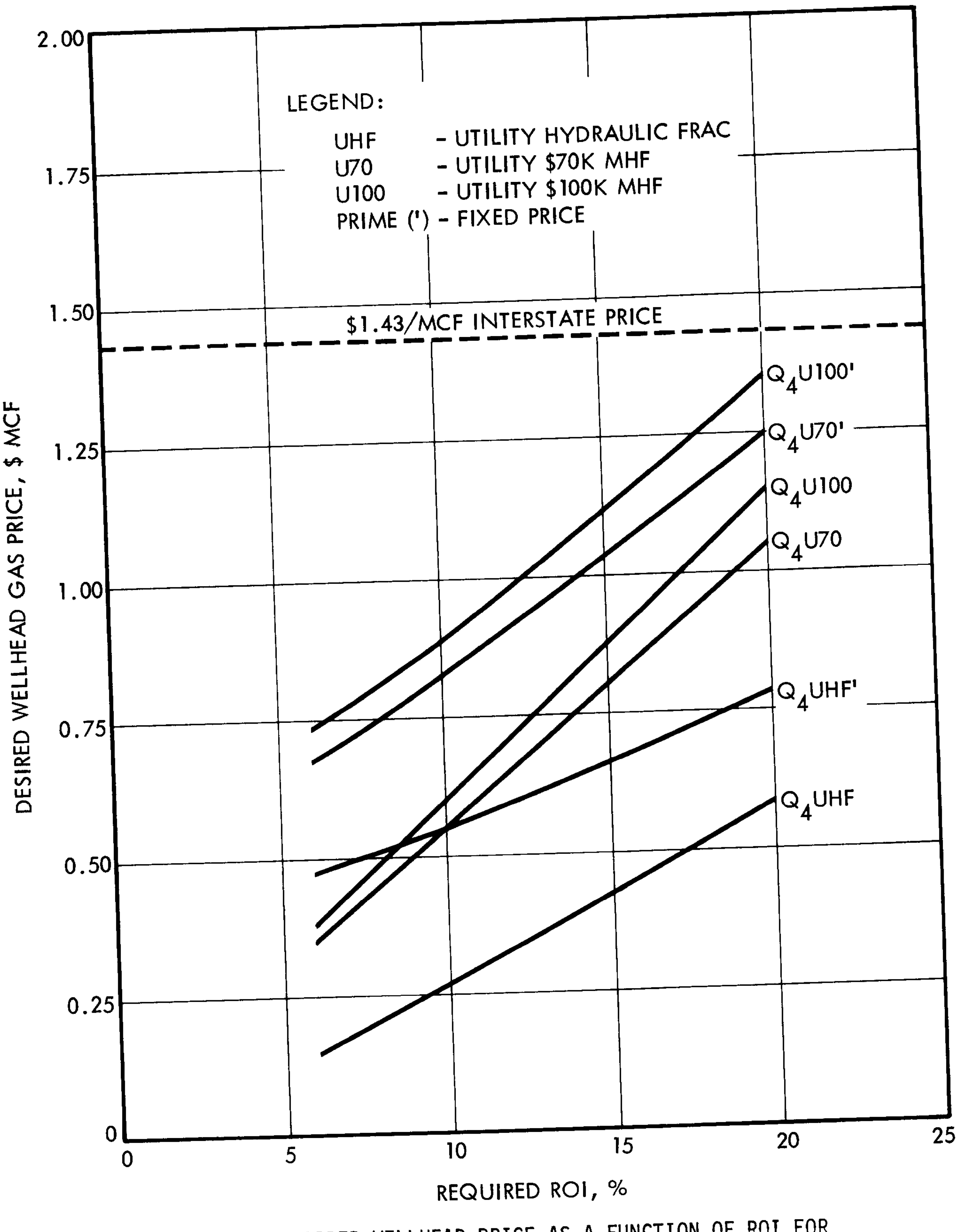

FIGURE 4-2. DESIRED WELLHEAD PRICE AS A FUNCTION OF ROI FOR SELECTED UTILITY MODEL CASES FROM TABLE 3-5 (SCENARIO B CURVE Q_4)

- In all instances where there is a price escalator of $0.04/year, the peak revenue inflow and peak positive net cash flow occurs after 15-20 years of production. The decline in output thereafter exceeds the effects of increases in price, and revenue begins to fall. At the same time, increasing operational and maintenance costs begin to cut heavily into the net cash flow.

- In cases where the wellhead gas price is held fixed throughout the life of the well, the initial required wellhead price is higher than when the price is escalated. As a result, the peak revenue occurs in the first year of operation and revenue declines thereafter. Payout periods will be shorter than with an escalating price (assuming the same ROI), whereas the PIR values remain unaffected.

- The investment tax credit and depletion allowance factors have only minimal effects on economic viability of the investment models considered because they apply only to tangible costs and not to well preparation and other costs.

The study results presented herein are based on generalized well production data. This points out the need to acquire well production data from the MHF and other advanced well stimulation projects in the eastern Devonian Shales. Production decline data from the initial periods of well production following stimulation could then be used to generate extrapolated production decline curves representative of total well performance. These data would constitute the basis for economic evaluation using appropriate assumptions for well drilling and stimulation costs. Economic sensitivity studies which demonstrate changes in relevant economic factors due to changes in well production decline characteristics and cost assumptions should also be considered in greater detail than was possible in this study.

APPENDIX A

THE ECONGAS PROGRAM

A computer model ECONGAS, representing an economic evaluation method which considers the life cycle of a gas well, has been formulated by TRW to evaluate the cost effectiveness of drilling ventures. The ECONGAS model was programmed in FORTRAN and is based on a modification of the following rate base expression.

$$P(k) = O\&M(k) + L(k) + Y(k) + D(K) + E(k) + .15\left[\left[D_o - \sum^{k} D(t)\right] + \left[E_o - \sum^{k} E_t\right] + WC\right] \tag{1}$$

where $P(k)$ = price in k^{th} year per MCF. (Note: In this report MCF and MMBTU are interchangeable. All gas produced is assumed to have a heating value of 1000 BTU.)

$O\&M(k)$	=	Operation and maintenance expenses in k^{th} year;
$L(k)$	=	Lease or royalty payments in the k^{th} year;
$Y(K)$	=	Prorated expense of dry holes and exploration;
$D(k)$	=	Depreciation expense for k^{th} year. Not a cash outlay.
$E(k)$	=	Depletion expense of producing well preparation and lease acquisition. Not a cash outlay;
D_o	=	Original investment in tangibles subject to depreciation, e.g., casing, pumps, and compressors;
E_o	=	Original outlays for intangibles subject to depletion; e.g., producing well preparation costs and lease acquisition;
WC	=	Prorated working capital per well (not subject to either depreciation or depletion); and
t	=	Time index (usually in years).

The following depreciation options are available for use in the ECONGAS program. Any one of them is acceptable to the IRS for income tax usage.

Straight Line Depreciation

$$D(k) = D_o/n \tag{2}$$

where n is the capital item life as specified by the IRS.

Sum of Digits Depreciation

$$D(k) = \frac{2(n - k + 1)}{(n + 1)\ n}, \tag{3}$$

where k = 1,2 ... n. The sum of the first n digits = $\frac{n(n+1)}{2}$

The first year's allowance factor is n divided by the sum of n digits, the second year's factor is n - 1 divided by the sum of digits, etc.

Double The Declining Balance Depreciation

$$D(1) = \frac{2D_0}{n}, \tag{4}$$

$$D(2) = 2\left(\frac{D_0 - D_1}{n}\right) \quad \ldots \quad D(k) = \frac{2}{n}\left[D_o - \sum_{t=0}^{k-1} D(t)\right]$$

Unit of Production (UOP)

Cost depletion and is also acceptable for depreciation (Lib. of Congr., 1974).

$$E(k) = \frac{Q(k)}{Q_0 - \sum^{k-1} Q(t)} \left[E_0 - \sum^{k-1} E(t)\right] \tag{5}$$

where Q_0 is the original estimate of well productivity and Q(k) is the actual gas production in the k^{th} year:

Equation 6 defines the basic ECONGAS model. The model can be employed using two different modes: (1) r specified and the desired price calculated, or (2) price specified and the desired r calculated. The input to the program states the desired return on investment "r", and calculates the gas price P (as \$/MMBTU) such that the desired return is received.

The procedure used in this study was to substitute a specified rate, say r_0, for r in the following equation. The resulting equation will be readily resolved for P.

$$- D_0 - E_0 - WC - W_0\mu + \sum_{t=1}^{29} \frac{[P(t)\ Q(t) -)\&M(t) - L(t) - D(t) - E(t)]\mu}{(1 + r)^t}$$

$$+ \sum_{t=1}^{29} \frac{D_t + E_t}{(1 + r)^t} \div \frac{C\ D_0}{1 + r} + \frac{WC}{(1 + r)^{29}} = 0 \qquad (6)$$

where

P(t) = The current projected interstate price for gas ($1.42/MMBTU plus gathering clause plus $0.04/yr escalator),

Q(t) = Estimated production prorated to a producing well for t = 1, 2,.. 29. Q(0) is defined as total well production expected over well life,

O&M(t) = Operating and maintenance expenses per year,

L(t) = Lease or royalty expenses per year,

D_o = Tangible costs that must be depreciated,

E_o = Intangible costs that must be cost-depleted,

W_o = All well preparation costs that can be expensed,

WC = Prorated working capital costs per well (cannot be depreciated, depleted or expensed),

$$D(t) = \frac{Q(t)\ [D_0 - \sum_{t}^{t-1} D(t)]}{Q_0 - \sum_{t}^{t-1} Q(t)} \qquad (7)$$

$$E(t) = \frac{Q(t)\ [E_0 - \sum_{t}^{t-1} E(t)]}{Q_0 - \sum_{t}^{t-1} Q(t)} \qquad (8)$$

μ = Income tax retention rate,

C = Tax credit rate on equipment investment currently,

r = Desired rate of return (ROI), and

t = Time index in years.

The main modifications of Equation 1 appearing in Equation 6 are inclusion of income tax credits and provision for maximum expensing. Tax credits for tangible investments are also included. Note that the evaluation procedure does not preclude an operator from expensing an intangible cost for evaluation purposes and capitalizing the same cost for purposes of stockholder reporting. This is allowed under IRS guidelines. Also, it is possible and is quite common for an operator to use one type of depreciation formula for evaluation purposes and report results based on another type of depreciation method for tax purposes. The ECONGAS model features are presented in Table A-1.

TABLE A-1. ECONGAS MODEL FEATURES

MODEL ELEMENT	TREATMENT	COMMENTS
Economic Unit	Complete new well	
Return Method	DCF	Conservative relative to average return
Income Taxes	Included	Rate is 0.50 to cover U. S. and state taxes
Expensing	All possible items expensed	Assumption is that total profits are enough to cover all tax credits
Depletion	"Cost" Method, UOP formula	Conservative assumption
Depreciation	UOP (default method)	UOP most conservative formula except for straight line
Cash Flow Timing	All expenditures except O&M and royalties assumed in "year zero"	
Dry Holes	Model basis is a producing well with production pro-rated for dry-hole ratio	Dry hole data ambiguous

The positive cash flows due to tax allowances for depreciation and depletion could have been entered directly into the model. But the format used facilitates calculation and display of net profits and income tax payments on a year-by-year basis should these values become of interest.

APPENDIX B

DETAILED WELL COST DATA

An itemized cost estimate for Devonian Shale drilling and completion to a depth of 3,500 feet is presented in Table B-1. Additional cost estimates for a Kanawha County, West Virginia well are presented in Table B-2.

Experience has shown that drilling cost is highest for a utility; a self-help company will "shop-around" somewhat and obtain a lesser drilling cost or attempt to do its own drilling; the independent producer will "shop-around" extensively to obtain the lowest drilling cost. Drilling costs selected by MERC correspond to (but are slightly higher than) estimates derived from plotting a limited number of cost data available. All cost data consider that the well was air drilled, stimulated and is productive.

Tangible costs as a function of total cost differ with type of company. The tangible well costs are 20% for a utility, 26.7% for a self-help company and 26.7% for an independent company. Expensed well preparation costs are the balance of total well costs.

The cost of drilling and completing a well in the U. S. has approximately doubled during the past seven years, with the cost of drilling fluid and additives increasing slightly over 100%. This indicates that drilling fluids have increased at slightly higher rates than most of the other purchased items. This price increase was caused by (1) the severe inflationary pressure in cost of goods and cost of operations experienced by all companies, (2) regaining a portion of the gross margin that was lost in the 1960s due to the actual decline in drilling mud prices during this period, and (3) the demand by customers for increased engineering service which is reflected in the price of drilling muds in the U. S. The gas wells in the Appalachian Basin were air drilled, therefore, drilling costs did not rise as rapidly.

Figure B-1 presents the average cost of drilling and equipping wells drilled in the United States in 1975 by depth intervals. The data indicates that these well costs vary from about $20 to $30 per foot at depths less than 5,000 feet, to a high of $144 per foot for wells 20,000 feet and over. The cost per foot for drilling fluid, if used in basins which allow shallow gas well

TABLE B-1. COST ESTIMATES - DEVONIAN SHALE DRILLING AND COMPLETION PROGRAM (1976)

SINGLE-WELL COST AND MATERIAL--3,500 FEET (AVERAGE DEPTH)

SITE PREPARATION	
Survey and Drilling Permit	250
Make location, Pits, Reclamation	5,000
DRILLING	
Drilling, 3,500 ft. @ $10.50/ft.	36,750
Surface casing and installation	
a. 25 ft. of 8-5/8" O.D. .264 wall well casing @ $6.77/ft.	169
b. Rig time, 15 hrs. @ $2,400/24 hrs.	1,500
c. Cement casing with 50 sacks cement and 1,000 lbs. $CaCl_2$	500
d. Rig time, 6 hrs. @ $2,400/24 hrs.	600
DRILLING FLUID (H_2O USUALLY OR AIR) PRODUCTION CASING	
a. 3,500 ft. of 4-1/2 O.D. J-55 @ $3.17/ft.	11,095
b. Hauling casing	250
c. Cementing production casing	
1. Pumping	1,045
2. Cement 424 sacks regular, $3.00/sack	1,272
Cement 424 sacks Pozmix A @ $1.25/sack	530
3. Service charge on cement and hauling	1,500
4. Taxes, etc.	180
5. Rig time - 6-1/2 hrs. @ $2,400/day	650
6. Miscellaneous material (packers, centralizers, wall cleavers, mud flush, salt for converting).	1,500
RIG LOGGING	
Downtime (lay down drillpipe and drill collars) 6 hrs.	600
a. Suite of logs, GR, density, caliper, temperature during drilling operation	2,500
b. Rig time for running logs, 8 hrs. @ $2,400/day	600

TABLE B-1. COST ESTIMATES - DEVONIAN SHALE DRILL AND COMPLETION PROGRAM (1976) (Continued)

SINGLE-WELL COST AND MATERIAL--3,500 FEET (AVERAGE DEPTH)

STIMULATION	
a. Service rig @ $40/hr. (10-hr. minimum)	
1. Swab, run Perf log, and perforate	$ 400
2. Swab back acid/after frac cleanup, 3 day $400/day	1,200
b. Perforating 10 holes/interval	1,000
Perforating log	400
c. Acid for perforating, 500 gal. @ 75¢/gal.	375
d. Foam-Frac (1,200 bbl)	
1. Pumping services (H_2C)	9,160
2. Pumping services (N_2)	6,561
e. Service rig to swab acid and assist foam frac 3 days @ $400/day	1,200
f. Breakdown (Acidize to bailout)	2,365
PRODUCTION IN LINE	
a. 3,400 ft. 2-3/8" O.S. tubing @ $1.68/ft.	5,712
b. Christmas tree, stuffing box	265
c. Service rig to run 2-3/8" tubing, 1 day @ $400/day	400
d. 3,000 ft. 2" line @ $1.50/ft.	4,500
e. Labor, installation 2" line pipe	4,500

TABLE B-2. PROJECTED COST IN DRILLING A BROWN SHALE WELL, KANAWHA COUNTY, WEST VIRGINIA (1976)

INTANGIBLE DEVELOPMENT COSTS	
1. Site Preparation	
a. Survey and drilling permits, building roads, clearing location and digging and leveling pits	$ 4,000
	$ 4,000
2. Drilling	
a. Hauling (all hauling except cement and moving rig and derrick)	$ 3,500
b. Contractor's drilling fee 5000' @ 8.00	40,000
c. Contractor's day rate $2,600/one day	2,600
d. Centralizing and floating equipment with scratchers	1,000
e. Cementing conductor and surface using (equipment and services)	3,500
	$50,600
3. Well Logging	
a. Well logs	$ 1,500
4. Stimulation	
a. Fracturing (shooting)	10,000
	$11,500
TOTAL	$66,100
TANGIBLE EQUIPMENT COSTS	
1. Well Equipment	
a. Conductor casing 30' of 13" O.D. @ $14.45/ft.	$ 430
b. Surface casing 500' of 9-5/8" O.D. @ $9.36/ft.	4,700
c. Production casing 2000' of 7" O.D. @ $5.96/ft.	11,900
d. Christmas tree	1,000
e. Valves and fittings	1,000
	$19,030
2. Lease Equipment	-
TOTAL COST OF WELL	$85,130

drilling, varies from $0.50/ft for wells under 2,500 feet to $20.00/ft for wells of 20,000 feet and deeper.

Although the cost data shown in Figure B-1 can vary significantly from one geographical area to another, it approximates very closely the cost for the wells drilled in the basin during 1975.

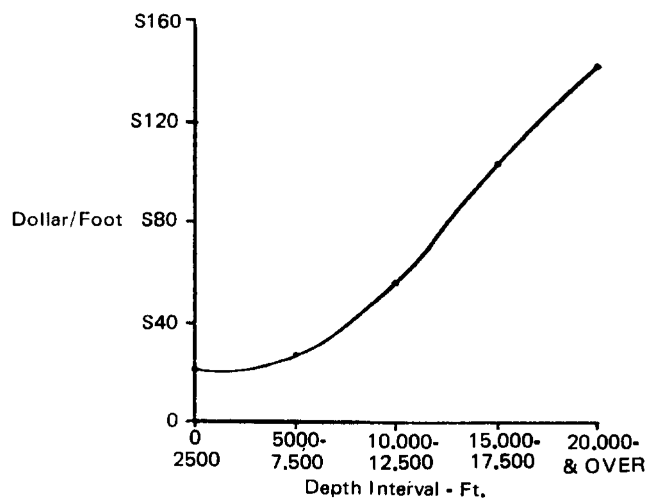

FIGURE B-1. COST OF DRILLING AND EQUIPPING WELLS BY DEPTH INTERVALS (U.S., 1975 DATA FROM BAROID AND API - JOINT ASSOCIATION REPORT, FEBRUARY 1977).

APPENDIX C

MEASURES OF GAS PRODUCTION ECONOMIC EVALUATION

Industry relies on various economic parameters to select investment opportunities. The economic measures used for evaluation of Devonian gas shale exploratory and in-field drilling projects by promotional or self-help ventures and utilities have not been uniform in the Appalachian Basin. This Appendix discusses some of the economic factors which are usually taken into account.

C.1 PROFITABILITY MEASURES

Historically, gas producers in the Appalachian Basin have not readily adopted new stimulation or drilling technologies. In order for the producers and local venture capital enterprises to restructure their conservative attitude toward the development of "tight" producing gas formations; the favorable economics of advanced stimulation technology has to be demonstrated.

Each type of operator in the Appalachian Basin has a particular set of constraints. For example, the utilities are concerned with Federal and State regulations governing the amount of profit which can be extracted from producing and selling gas to the consumer. Independent operators are concerned about the availability of the supply of natural gas upon demand and the cost of this gas with respect to the price of substitute fuels, such as propane.

No single measure can provide an accurate rating of an investment. A combination of profit indicators will spotlight the strong and weak points of various shale gas stimulation strategies. Conventional measures commonly used by venture capital investors and gas producers include:

- Payout time
- Discounted cash flow rate of return
- Profit/investment ratio
- Average return of either invested capital, equity or rate base
- Net present value of future income.

These measures are discussed separately in the following paragraphs:

PAYOUT TIME is the oldest and simplest indicator by which the majority of oil and gas properties are judged. This measure is particularly preferred by the independent operators in evaluating natural gas drilling "plays" in the Appalachian Basin. The independent operator's financial well-being is conditioned on being able to turn over his money at regular intervals. He typically operates with relatively short term borrowed capital on which he hopes to make enough profit to serve, in turn, as seed money for the next drilling venture. Payout time is simply the amount of time required to recover the investment and is expressed mathematically as:

$$\text{PAYOUT TIME} = \frac{\text{\$ INVESTED}}{\text{(\$ AVERAGE PROFIT/UNIT TIME)}} \tag{1}$$

This indicator is popular with the Appalachian operators because of its simplicity and its intuitive appeal. Graphically, the concept of payout time can be expressed as shown in Figure C-1. The chief argument against payout is that much information is discarded. It does not take into consideration the rate of earnings over the life of the investment after payout. Furthermore, it does not measure the total profit, nor measure the life of the investment itself. The flow of profits during the recovery period can be averaged to calculate payout. The time pattern of receipts is not significant once the recovery period has been defined. An advantage is that the payout time gives a measure of the speed with which the investment is returned. At payout, the amount of risk capital becomes zero. It is obvious that the shorter the time period--the less will be the risk. It is also obvious that, all other things being equal, the operator will invest in projects having the shortest possible payout time.

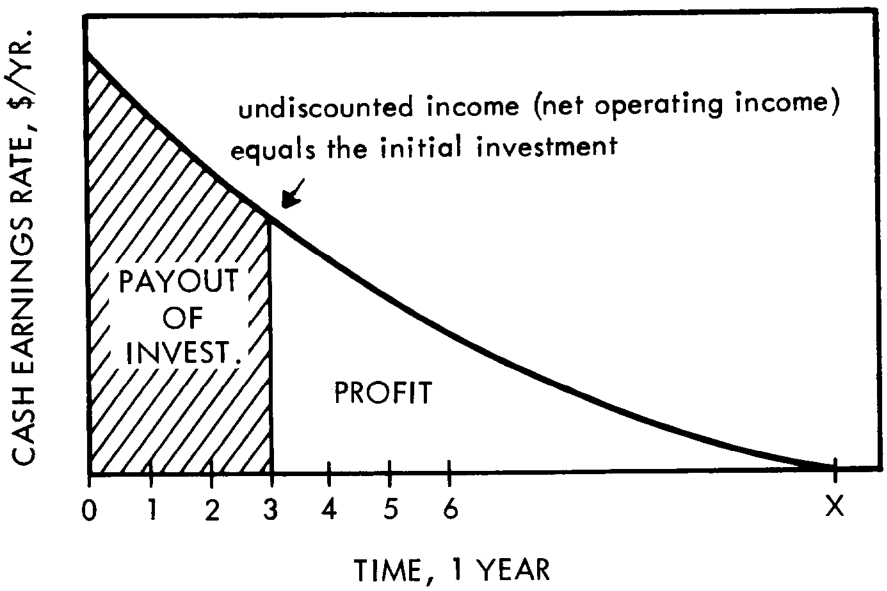

FIGURE C-1. PAYOUT TIME AS A MEASURE OF PROFITABILITY IN DEVONIAN GAS SHALE DRILLING VENTURES.

DISCOUNTED CASH FLOW RATE OF RETURN (DCF) is basically the reverse of determining the present worth of an investment. This approach, preferred by most large companies, takes the time factor into account and does not involve the assumption of an arbitrary discount rate. It is defined as that "r" which equates the present value of expected cash outflows with the present value of expected cash inflows in the following expression:

$$\sum_{t} \frac{C(t)}{(1 + r)^t} = 0 \tag{2}$$

where C(t) is the net sum of all cash inflows and outflows for year t, and it is the last period in which a cash flow is expected.

In other words, the DCF return, sometimes called the internal rate of return when used as a discount factor, makes the project net present value (NPV) zero. The chief advantages of the DCF approach are:

- The time value of money is considered.
- The returns do not need to be scaled to the project size.
- The calculations are independent of any assumptions about project financing or corporate capital structure.
- Discount rate is solved for, not specified.

The chief arguments against DCF return are:

- Complexity of calculations.
- An implied assumption of the method is that the investor will be able to obtain a compounded rate of return on its assets equal to calculated internal return. However, this objection does not necessarily invalidate DCF rate of return as a ranking measure.

Finally, the following general observation is made about average return versus discount measures. For all the average return methods, the operator must distinguish between expense and capital costs. The Internal Revenue Service gives some but not complete guidance on the distribution. As an example, for tax purposes dry holes may be expensed, but the operator must decide whether he should or is permitted to capitalize dry hole costs. Similarly, the IRS does not care whether research and development cost is expensed or capitalized and the operator must make the final decision.

On the other hand, in the DCF method it is immaterial whether an outlay is expensed or capitalized provided that maximum advantage is taken of the income tax laws. Further, the IRS has quite explicit regulations as to what constitutes a legitimate tax expense. Hence, inherently the DCF method requires less judgment on the operator's part than average return methods.

PROFIT/INVESTMENT RATIO (PIR) is a measure of risk. The profit per dollar invested is defined as:

$$PIR = \frac{\text{CUMULATIVE NET CASH FLOW}}{\text{TOTAL INVESTMENT}} = \frac{\text{TOTAL PROFIT}}{\text{TOTAL INVESTMENT}} \tag{3}$$

For example, a project which earned a total cumulative profit of $9,000 on a $10,000 investment would have a Profit/Investment Ratio of 0.9. No timing is involved, but PIR indicates the amount of profit to be made in proportion to the investment and may give a clue to the profitability of the project. General accepted practice is to rank any drilling project with a PIR of less than 1 as having excessive risk.

AVERAGE RETURN is defined by the following equation:

$$\% \text{ AVERAGE RETURN} = \frac{\sum_t \$ \text{ NET PROFIT}}{\sum_t \$ \text{ CAPITAL BASE}} \times 100 \tag{4}$$

where the summation is over project life and "t" is a time index.

Note that normally the capital base declines over project life because of equipment depreciation and resource depletion. Therefore, it is necessary to consider both profits and investments on a year-by-year basis.

The capital base can be defined in several ways as follows:

- Total investment of assets deployed
- Total equity (non-debt) investment
- Total rate base which is similar to total investment except that the composition of the base is defined by a federal or local regulatory agency. Practically speaking, this means that certain items that an operator would want to include in the base are excluded by the regulatory body.

The chief arguments for average return are:

- An average return (or rate base) format is often required by regulators.
- Average return on assets is popular with certain firms since the measure is independent of financial arrangements and is fairly easy to calculate and understand.
- Average return on equity is popular with some companies since return on equity (expressed as earnings per share) strongly influences common share prices.

The chief argument against the average return method is:

- The calculation ignores the time value of money. A dollar in hand today is worth more than a dollar a year from today. Thus, information on the time pattern of receipts and outlays is largely wasted in the average return method.

NET PRESENT VALUE accounts for the time value of money by decreasing in a systematic way the value of future receipts and expenditures. It can be considered as the reverse of compound interest. To illustrate:

Future Value of \$1 compounded at r% interest = \$1 $(1 + r)^n$

where n is the number of time periods of deposit. Then PV of \$1 $(1 + r)^n$, n periods from now = \$1 (from above) and PV of \$1.00 n periods from now = $\frac{\$1}{(1 + r)^n}$

Then defining C(t) as the net sum of all cash inflows and outflows for year t,

$$NPV = \sum_t \frac{C(t)}{(1 + r)^t} \text{ by definition} \tag{5}$$

The output of a NPV calculation is a dollar value which may be either positive or negative. If the value is negative, the project should be rejected, but if the value is positive the project may or may not be acceptable.

It is rather difficult to rank projects by positive NPV since a project involving large expenditures with everything else being equal has a larger NPV than a smaller project. Hence NPVs are sometimes normalized by dividing by the initial investments to obtain "return coefficients".

The chief argument for NPV is that the time value of money is taken into account. Also the method of project financing is immaterial but the analyst must have some idea of the parent corporation financial structure. The chief arguments against NPVs are:

- As indicated above, there is a scaling problem with projects of different size. Although scaling might be overcome by use of "return coefficients", these coefficients are not widely used in industry.

- To perform a NPV calculation, it is necessary to specify a discount rate ("r" in the above illustration). Theoretically the discount rate is the cost of capital to the corporation. This cost, in turn, is defined as the weighted average of the cost of debt and equity to the corporation. The cost of debt is usually taken as the weighted average of market interests on the various debt issues outstanding. (Convertible debentures are a special problem.) But there is no generally accepted method of calculating the cost of equity. In fact, considerable controversy surrounds the issue.

C.2 SENSITIVITY MEASURES

Risk is a function of the reliability of the data, the accuracy of the forecast and the sensitivity of profit to variations in the data. The sensitivity of profit is roughly proportional to the sensitivity of revenue to changes in the data (Figure C-2). Although the Devonian gas shales are not thought of as being high risk projects, it should be assumed that some sort of risk analysis will be performed by the operator.

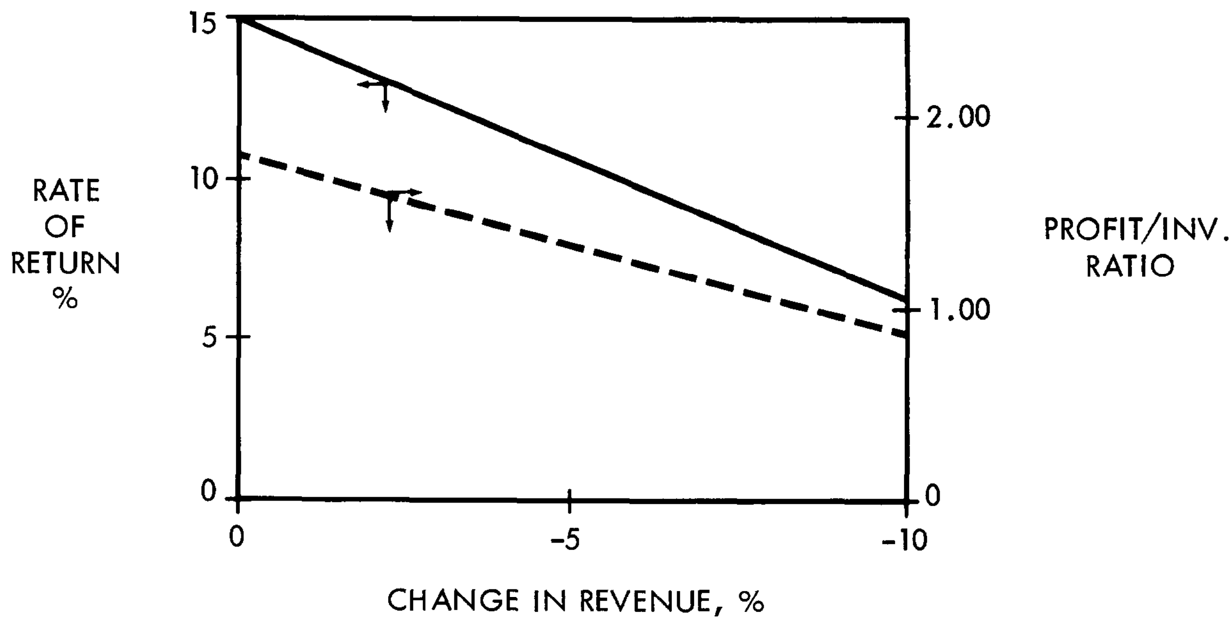

FIGURE C-2. SENSITIVITY MEASURES OF THE VARIATION IN REVENUE.

APPENDIX D

PRICE HISTORY OF NATURAL GAS IN THE APPALACHIAN BASIN

Figure D-1[1] illustrates the trend of the field price of natural gas in the Appalachian region. In 1950, the average natural gas price at the wellhead was $0.25 per MCF. During the late 1960's the price increased to $0.27 per MCF, and the first price increase of any significance to the producer came in 1972.

FPC Opinion No. 699H established the price of natural gas at $0.52 per MCF, with an escalation of $0.01 per annum. This price was upheld by FPC Opinion No. 770 for gas solid under contracts where pricing provisions have expired, which expiration occurred, or a new price was negotiated, subsequent to January 1, 1973. Gas produced after 1/1/73 is called by the FPC "new gas".

FPC Opinion No. 770 established two basic rates for new gas dedicated to interstate commerce.

- For gas of 1973-74 vintage (1/1/73 to 12/30/74) the rate was established at $1.01 per MCF without an escalation clause.
- For gas of 1975-76 vintage, the rate is $1.42 with a quarterly escalation of $0.01.

Both prices include BTU adjustment, state and federal severance or similar taxes and gathering allowances. Opinion No. 770 provided a "fully cost-based and justified" rate. The $0.52 per MCF rate for renewal contracts, as set forth in Opinion No. 699H, was also maintained.

FPC Opinion No. 770A modified the $1.01 per MCF rate established for natural gas from wells commenced during the 1973-74 biennial period to $0.93 per MCF, with a $0.01 per annum escalator in each calendar year.

The FPC clarified the interpretation of what price natural gas is eligible for under Opinion No. 770A as follows.

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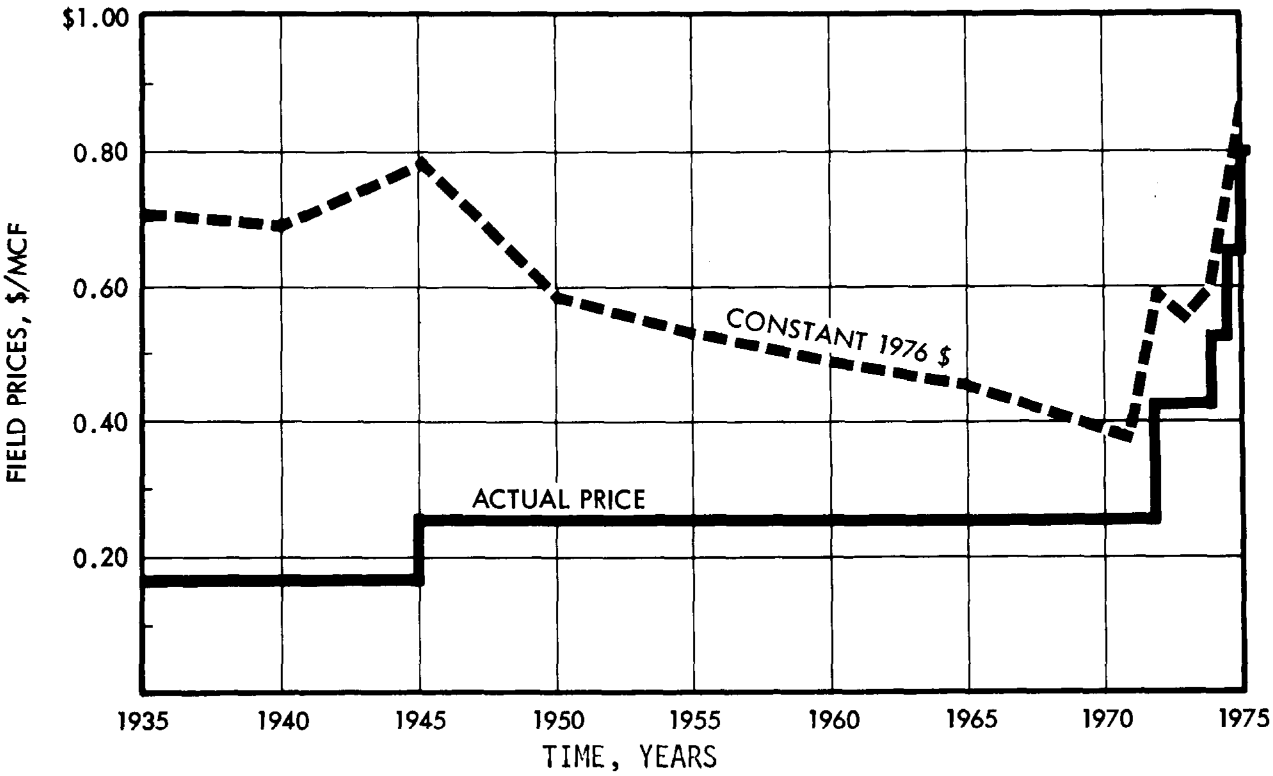
[1]Jack, S.W., Jr. and Stewart, R.S., 1975. Economics of Pennsylvania shallow production. SPE Reprint No. 5446, East. Reg. Meet. SPE, Charleston, West Virginia, November 6-7, 1975, 8 p.

FIGURE D-1. COMPARISON OF ACTUAL FIELD PRICES OF NATURAL GAS PRODUCED IN PENNSYLVANIA WITH THOSE PRICES IN CONSTANT 1976 DOLLARS.



- There was no cost-based rationale for permitting recompletion of existing gas wells in known producing reservoirs, prior to the 1973-74 and the 1975-76 biennium FPC price structuring, which allowed the operators to receive the then-applicable national rates of $1.01 per MCF and $1.42 per MCF, respectively.

- All gas produced from wells which commenced on or after January 1973 shall be priced at the applicable national price rate which is based on the wells' "spud-in" date, regardless of the date of completion or recompletion.

- Any gas produced from recompletions in wells commenced prior to January 1, 1973, shall receive the rate of $0.52 per MCF, with the $0.01 per annum escalator as established in Opinion No. 699H.

It is assumed herein that all gas produced by advanced stimulation technologies from the Mississippian-Devonian shales will be new production subject to the interstate rate of $1.42 per MCF and an intrastate rate ranging from $2.00 per MCF in eastern Kentucky to the winter spot market of $3.00 per MCF in Ohio. The present price structure is presented in Table D-1 and includes the proposed price for "new gas" after 1/1/78 from the National Energy Plan.

TABLE D-1. PRESENT PRICE STRUCTURE FOR CURRENT PRODUCTION OF GAS IN THE APPALACHIAN BASIN.

	WEST VIRGINIA	KENTUCKY	OHIO
1. INTERSTATE GAS PRODUCED:			
(1) Prior to 1/1/73			
a. Base b. Escalator Clause	0.6485*	0.52 MCF	0.52 MCF
(2) 1/1/73 - 12/31/75			
a. Base	$0.93 MCF	$0.93 MCF	$0.93 MCF
b. Escalator Clause	$0.01/yr	$0.01/yr	$0.01/yr
c. Gathering Clause	0.01	0.01	0.01
d. BTU Adjustment Clause	$(\frac{BTU}{1000})$ X Base	$(\frac{BTU}{1000})$ X Base	$(\frac{BTU}{1000})$ X Base
e. Tax Rebate Clause	(Base X State + Base X County)	(Base X State + Base X County)	(Base X State + Base X County)
(3) After 1/1/76			
a. Base	$1.42 MCF	$1.42 MCF	$1.42 MCF
b. Escalator Clause	$0.04/yr	$0.04/yr	$0.04/yr
c. Gathering Clause	$0.01/yr	$0.01/yr	$0.01/yr
d. BTU Adjustment Clause	$(\frac{BTU}{1000})$ X Base	$(\frac{BTU}{1000})$ X Base	$(\frac{BTU}{1000})$ X Base
e. Tax Rebate Clause	(Base X State + Base X County)	(Base X State + Base X County)	(Base X State + Base X County)
(4) Price proposed in the National Energy Plan 1/1/78	$1.75	$1.75	$1.75
2. INTRASTATE GAS	$2.25-$2.50	$2.00-$2.25	$1.70 $3.00**

*IOGA Suit (1975) - Cabot (1% of the total gas production in West Virginia) was not part of the suit and is paying $0.12-$0.16 MCF under old contracts.

**Winter spot market.